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Modeling Guideline for Determination of Tank System Potential Peak Instantaneous Vapor Flow Rate

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0	7/12/2016	Initial Release	AMO/JVH/KM
1	7/26/2016	Incorporation of EPA Comments	AMO/JVH/KM
2	9/1/2016	Finalized Document	AMO/JVH/KM

Introduction

This Modeling Guideline has been drafted in accordance with the requirements of Consent Decree (XX-X-X-X-XXXXX) – X:XX-cv-XXXXX XXX between the United States Environmental Protection Agency (EPA), State of North Dakota and Slawson Exploration Company, Inc. in order to meet the requirements of the injunctive relief section (Section IV) specific to the engineering evaluation of the Vapor Control System(s) at well pads and Tank Systems subject to the aforementioned consent decree.

The Modeling Guideline is intended to describe the engineering calculation methodologies, direct measurement approaches, and analytical requirements which contribute to the elements used to determine the Potential Peak Instantaneous Vapor Flow Rate. The contributing elements are grouped into the following categories:

1. Potential Peak Instantaneous Liquid Flow Rate used in combination with the Maximum Potential Flash Gas Oil Ratio and Flash Gas Water Ratio to determine the peak Flash Gas generated;
2. Working/Breathing/Standing Emissions and Losses common to Storage Tanks; and
3. Other potential vapor sources directed to the Vapor Control System.

The entirety of the above elements determines the Potential Peak Instantaneous Vapor Flow Rate. The Potential Peak Instantaneous Vapor Flow Rate is a critical input into the Engineering Design Standard.

This document may be periodically updated as needed to incorporate changes to methodology, correction of typos, edits for clarity, etc.

Definitions

API Gravity – The weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and expressed in degrees.

Bubble Point – The condition (temperature and pressure) at which the Pressurized Liquid is just ready to evolve a vapor phase (i.e., boil). An oil mixture within a Separator is considered to be at or near its Bubble Point.

Bubble Point Check – A Pressurized Liquid sample quality check where a comparison is made between the calculated Bubble Point temperature and pressure based on the Pressurized Liquid composition and the Separator temperature and pressure recorded during sampling. Samples where the difference between the calculated Bubble Point temperature and/or pressure and the temperature and/or pressure, respectively, exceeds ±30 percent typically require a Bubble Point Correction or resampling.

Bubble Point Correction – A procedure where the composition of a Pressurized Liquid can be "corrected" to its bubble point at Separator temperature and pressure.

CARB Protocol – California Environmental Protection Agency Air Resources Board (CARB) Draft Test Protocol for Crude Oil, Condensate, and Produced Water Sampling and Laboratory Procedures for the Determination of Methane, Carbon Dioxide, and Volatile Organic Compounds (December 2010 draft or latest draft or final versions).

Dump Event – When a Dump Valve or controls open to allow liquid flow from the Separator or Heater-Treater to a VRT, Tank System or Storage Tank.

Dump Valve – The on/off valve which allows liquids to flow from the Separator or Heater-Treater vessel.

Flash or Flashing – The release of hydrocarbons and other dissolved gases from liquid to gas phase as a consequence of a reduction in pressure or change in temperature.

Flash Liberation Analysis – The laboratory methodology described in the CARB Protocol. The results are expressed as gas to oil ratio or gas to water ratio in terms of standard cubic feet per stock tank barrel and may include the composition and properties of the Flash Gas.

Flash Gas – Gas liberated from liquid phase due to a drop in pressure from Separator, Heater-Treater, or other process condition to stock tank or other pressure and temperature conditions

Flash Gas-Oil-Ratio (FGOR) – The ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Flash Gas-Water-Ratio (FGWR) – The ratio of the volume of gas at standard temperature and pressure that is produced from a volume of produced water when depressurized to standard temperature and pressure.

Malfunction – Any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Maximum Operating Conditions – The maximum foreseeable conditions during Normal Operations, generally the Heater-Treater or Separator maximum operating pressure and minimum operating temperature, at a specific location, used in the determination of the Potential Peak Instantaneous Vapor Flow Rate. These are the conditions that result in the maximum amount of vapor Flash at the Tank Systems, but do not include conditions due to mechanical failure or abnormal operations (e.g. a stuck-open Dump Valve), those conditions that are prevented from occurring due to installed safeguards (e.g. high pressure shut downs, PSV or other relief device), or any other condition that cannot reasonably be expected to occur.

Normal Operations – All periods of operation, excluding Malfunctions. For Storage Tanks at Well Pads, Normal Operations includes, but is not limited to, liquid Dump Events from Separator(s) or Heater-Treater(s).

Potential Peak Instantaneous Liquid Flow Rate – The maximum instantaneous volume of liquids discharged from the Separator, Heater-Treater or Vapor Recovery Tower to the Tank System which occurs at Maximum Operating Conditions.

Potential Peak Instantaneous Vapor Flow Rate (PPIVFR) – The maximum instantaneous amount of vapors from a Storage Tank or Tank System routed to a Vapor Control System during Normal Operations, including flashing, working, breathing, and standing losses, as well as other sources as determined using this Modeling Guideline.

Pressurized Liquids – Pressurized Produced Oil immediately upstream of the Storage Tank(s) or pressurized Produced Water immediately upstream of the Storage Tank(s).

Produced Oil – Oil that is separated from extracted reservoir fluids during Production Operations.

Produced Water – Water that is separated from extracted reservoir fluids during Production Operations.

Production Operations – Extraction, separation using Separators and or Heater-Treaters, and temporary storage of reservoir fluids from an oil and natural gas well at a Well Pad.

Separator – A heated or unheated pressurized vessel designed to separate produced fluids into their constituent components of oil, natural gas, and water.

Storage Tank – A unit that is constructed primarily of non-earthen materials (such as steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of produced reservoir fluids (i.e. Produced Oil or Produced Water).

Tank System – One or more Storage Tanks, with at least one Produced Oil Storage Tank, that share a common Vapor Control System.

Vapor Control System (VCS) – The system used to contain, convey, and control vapors from one or more Storage Tank(s) (including Flashing, working, breathing, and standing losses), as well as any natural gas carry-through to Storage Tanks. A Vapor Control System includes a Tank System, piping to convey vapors from a Tank System to a combustion device and/or Vapor Recovery Unit, fittings, connectors, liquid knockout vessels or vapor control piping, openings on Storage Tanks (such as thief hatches and any other pressure relief devices ("PRDs")), and emission control devices.

Vapor Recovery Tower (VRT) – A vessel located downstream of a Separator or Heater-Treater used to reduce the pressure of liquids discharged from such vessels prior to discharge to the Tank System to reduce Flash Gas. Gas phase from the VRT is routed to a Vapor Recovery Unit.

Well Pad – A surface site with one or more Storage Tank(s) capable of receiving Produced Oil from Production Operations.

Working, Breathing, Standing Emissions or Losses (W/B/S) [Reference 1] – Emissions that can occur as vapors are displaced from the Storage Tank headspace when the tank is filled (working) or when there are temperature or pressure fluctuations in the Storage Tank (breathing and standing).

Acronyms

API	American Petroleum Institute
CARB	California Environmental Protection Agency Air Resources Board
FGOR	Flash Gas to Oil Ratio
FWOR	Flash Gas to Water Ratio
ISA	International Society of Automation
PPIVFR	Peak Potential Instantaneous Vapor Flow Rate
PSI	Pounds per Square Inch
VCS	Vapor Control System
VRT	Vapor Recovery Tower
W/B/S	Working, Breathing and Standing Losses

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Potential Peak Instantaneous Liquid Flow Rate

The Potential Peak Instantaneous Liquid Flow Rate needed to determine the PPIVFR can be impacted by a variety of operating conditions including Separator operating pressures and temperatures, simultaneous Dump Events from multiple Separators, and process controls, such as Dump Valves, control valves, reducing orifices, or cross equipment automation. The Potential Peak Instantaneous Liquid Flow Rate can be determined by applying the following engineering methodologies, as appropriate, for the given operating conditions and equipment configurations:

1. Incompressible Fluids Non-Choked Flow Calculated via Equation 1, ISA-75.01.01-2007 (60534-2-1- Mod) - Flow Equations for Sizing Control Valves (Draft 1) [Reference 2];
2. Incompressible Fluids Choked Flow Calculated via Equation 3, ISA-75.01.01-2007 (60534-2-1- Mod) - Flow Equations for Sizing Control Valves (Draft 1) [Reference 2];
3. Liquid Flow Through Orifices, Nozzles, and Venturi via Equation 4-5, CRANE – Technical Paper No. 410 [Reference 3];
4. Control Valve Sizing and Selection via Equation 3-8, CRANE – Technical Paper No. 410 [Reference 3];
5. Direct measurement via a calibrated flow meter at Maximum Operating Conditions; or
6. Engineering calculation based on high and low liquid level set points in the Separator, Dump Event duration, and additional Produced Oil fed into the Separator during the Dump Event.

The aforementioned calculations, as appropriate, will be performed with valve, orifice, and equipment specifications provided by the manufacturer and representative hydrocarbon liquid properties. Recognized industry methods and good engineering practices will be utilized to obtain appropriate information when manufacturer or representative liquids information is unavailable.

Produced Oil may, under certain conditions, flash as it flows through the Dump Valve. The equations in the sources above assume that the fluid remains liquid as it travels through the Dump Valve. This assumption results in a calculated flow rate that may be higher than the actual flow rate. Potential Peak Instantaneous Liquid Flow Rate can be determined by applying the following engineering methodologies for multiphase fluids:

1. Improved control valve sizing for multiphase flow [Reference 4].

The Potential Peak Instantaneous Liquid Flow Rate will account for all sources of liquid entering the Tank System including simultaneous Dump Events from multiple Separators. Dump Events controlled through automation, timers, etc. in a manner which prevents them from occurring simultaneously will be evaluated as appropriate based on such operation.

Maximum Potential Flash Gas to Oil/Water Ratio

The Maximum Potential FGOR and FGWR are determined in order to quantify the total volume of Flash Gas produced at Maximum Operating Conditions and Produced Oil/Produced Water volumes. FGOR and FGWR are determined based on the maximum volume rate of Flash Gas divided by the maximum volume rate of liquid throughput. FGOR and FGWR may also be provided by laboratory Flash Liberation Analysis.

The FGOR/FGWR value can be determined through a variety of methods used individually or in combination. Methods that may be used include but are not limited to:

1. Obtaining a site-specific or representative Pressurized Liquid sample and hydrocarbon composition analysis in accordance with sampling procedures prescribed in the CARB Protocol [Reference 5]. Utilizing the Pressurized Liquids sample analysis and completing a Flash simulation by means of process modeling software, such as E&P TANKS©, ProMax®, Aspen HYSYS®, etc., from Maximum Operating Conditions or sampling conditions to the Tank System conditions. Determining the ratio of vapor flow rate to Pressurized Liquids flow rate from the process simulation model. The Peng-Robinson or other accepted equations of state should be utilized in the process model to obtain accurate results.
2. Obtaining a representative Pressurized Liquid sample collected in accordance with and using Flash Liberation Analyses procedures prescribed in the CARB Protocol [Reference 5].
3. By obtaining direct flow measurements of the Pressurized Liquids leaving the last stage of separation and the vapor leaving the Tank System. Flow meters need to be calibrated and appropriate for the type of fluid being measured.
4. Through the use of empirical Flashing correlations, such as Valko-McCain [Reference 6], etc., that can be properly applied based on the facility operating conditions and available data, such as liquid API gravity, etc.

A Bubble Point Check and, if necessary, a Bubble Point Correction should be conducted when utilizing Pressurized Liquid sample analyses.

W/B/S Determinations

Evaporative W/B/S Losses are to be included in the determination of the PPIVFR as they are a potential source of vapor volume to the VCS.

Working Losses

Vapors resulting from working losses are due to the changing liquid level and available head space within the Tank System. Working losses from fixed roof Storage Tanks can be calculated by, but not limited to, the following methods:

1. API Standard 2000, A.3.2 – Liquids Movement adjusting air for gas density [Reference 7];
2. AP-42, Section 7.1 – Organic Liquid Storage Tanks, 7.1.3.1.2 Working Loss from Fixed Roof Tanks [Reference 8]; or
3. Displacement calculations in conjunction with production volumes and Storage Tank pressure

Breathing/Standing Losses

Vapors resulting from breathing/standing losses are due to the thermal expansion and contraction of gas/vapor in the Storage Tank headspace during the diurnal heating cycle.

Breathing losses are for Storage Tanks associated with Production Operations are typically much lower than losses from Flashing and Working. Breathing/standing losses from fixed roof Storage Tanks can be calculated by, but not limited to, the following methods:

1. API Standard 2000, A.3.3 – Thermal Effects adjusting air for gas density [Reference 7]; or
2. AP-42, Section 7.1 – Organic Liquid Storage Tanks, 7.1.3.1.1 Standing Storage Loss from Fixed Roof Tanks [Reference 8].

Other Potential Vapor Sources

All potential vapor sources other than Flashing and W/B/S losses that are or may be routed to the VCS will be evaluated and, if deemed impactful based on engineering judgement, accounted for and quantified. Such sources may include, but are not limited to:

1. Transfer and loading systems
2. Equipment blanket gas
3. Equipment purge gas
4. Natural Gas operated pneumatic devices (i.e. pumps, valves, etc.)
5. Produced gas from Separator vessels not routed to a control device independent of the VCS or a gas gathering pipeline
6. Overhead vapors from a VRT not routed to a control device independent of the VCS or a gas gathering pipeline
7. Separator vortex gas pass-through commingled with the separated liquids stream routed to the Tank System

These other potential vapor sources may be calculated by, but not limited to, the following methods:

1. AP-42, Section 5.2 – Transportation and Marketing Of Petroleum Liquids [Reference 8];
2. Manufacturer Specifications
3. Aforementioned Potential Peak Instantaneous Liquid Flow Rate and Maximum Potential Flash Gas to Oil/Water Ratio methods
4. Direct measurement

The identified other potential vapor sources will be noted and quantified through the use of vendor provided information, equipment specifications, industry accepted engineering calculations, process modeling software, direct measurement, and other appropriate means.

Data Uncertainty

Uncertainty may be inherent in measurements, Pressurized Liquid sampling and analyses, assumptions, calculation, statistical analyses, software tools and other data elements. The engineer may apply a discretionary engineering safety factor as appropriate to individual data inputs or to the resulting PPIVFR to mitigate potential bias and ensure the resulting PPIVFR is representative of Maximum Operating Conditions.

Changes to PPIVFR

PPIVFR may increase or decrease as a result of changes to operations or equipment at a facility. Examples of changes which can affect PPIVFR include but are not limited to:

1. Changes to Dump Valve size or trim

2. Addition or removal of a Produced Oil or Produced Water source such as a Separator
3. Addition of staged separation or VRT to reduce Flashing
4. Changes to Maximum Operating Conditions
5. Changes to or addition of controls preventing simultaneous Dump Events

The PPIVFR may need to be recalculated if any of the above changes occur.

Documentation

The assumptions, calculation and statistical methodologies, analytical results, software tools, and any essential information utilized in the determination of the Potential Peak Instantaneous Liquids Flow Rate, FGOR/FGWR, W/B/S Losses, and quantification of other vapor sources will be documented in a manner which fosters understanding and transparency for parties reviewing the determinations (i.e. 3rd Party Audit). Information may be provided in hard copy or electronic format dependent on the source and availability.

Bibliography

[1] American Petroleum Institute, Evaporative Loss Measurement, Section 1 – *Evaporative Loss from Fixed-Roof Tanks*, Fourth Edition (October 2012) and earlier editions.

[2] International Society of Automation, *Flow Equations for Sizing Control Valves*, Copyright 2007, ISA-75.01.01-2007 (60534-2-1 Mod).

[3] Crane Company, Flow of Fluids Through Valves, Fittings and Pipe – Technical Paper No. 410, Copyright 2013.

[4] Diener R., Kiesbauer, J., Schmidt, J., "Improved control valve sizing for multiphase flow" Hydrocarbon Processing (March 2005).

[5] California Environmental Protection Agency Air Resource Board, *Draft Test Procedure - Determination of Methane, Carbon Dioxide, and Volatile Organic Compounds from Crude Oil and Natural Gas Separation and Storage Tank Systems*, June 2012 Revision.

[6] Valko, P.P., McCain Jr, W.D., "Reservoir oil bubblepoint pressures revisited; solution gas-oil ratios and surface gas specific gravities." Journal of Petroleum Science and Engineering 37 (2003): 153-169.

[7] American Petroleum Institute, *Venting Atmospheric and Low-pressure Storage Tanks*, 7th ed., Copyright 2014, API Standard 2000.

[8] US Environmental Protection Agency, Office of Air Quality Planning and Standards, Office of Air and Radiation, *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, AP-42, 5th ed., 1997.